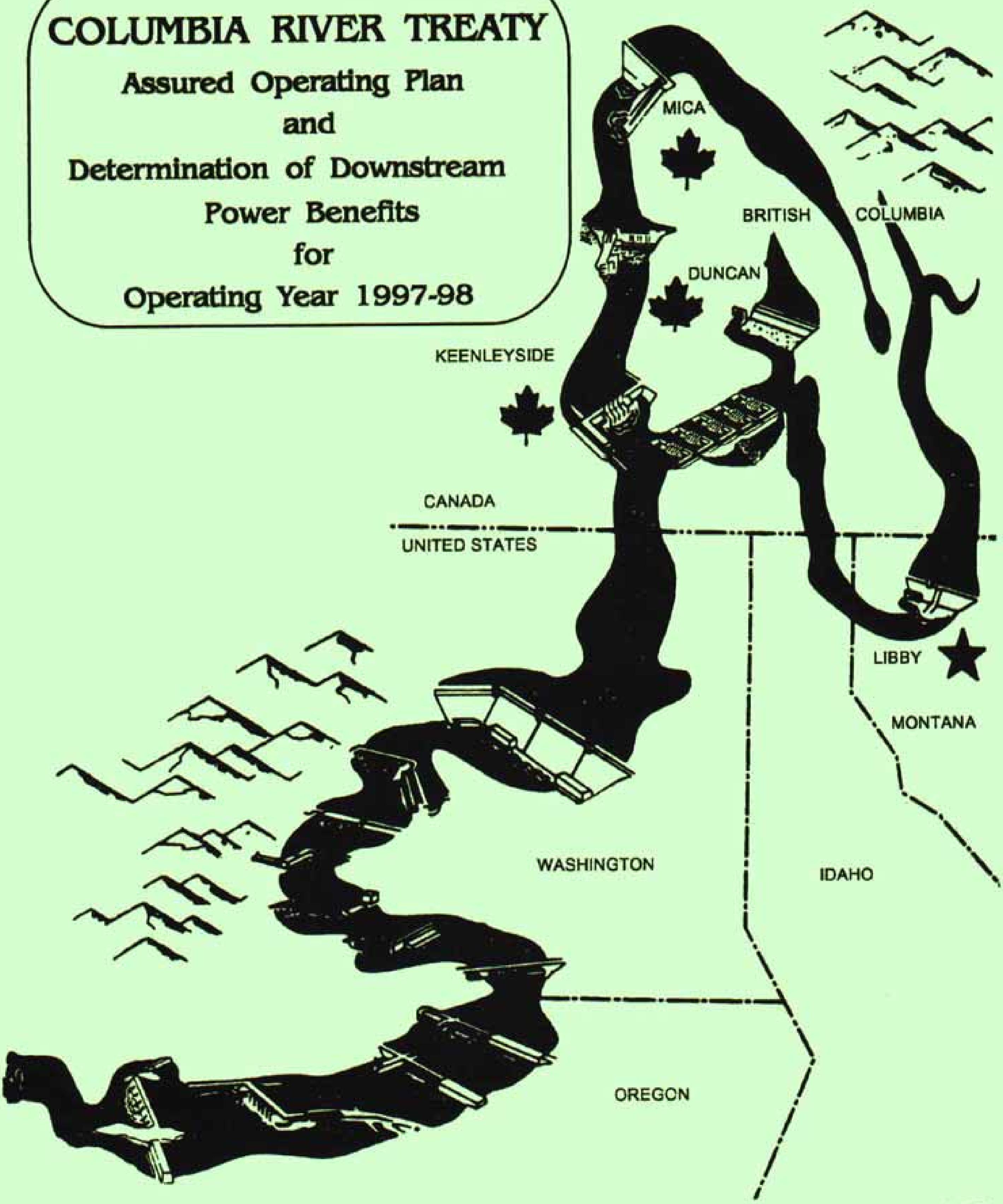
COLUMBIA RIVER TREATY

Assured Operating Plan
and
Determination of Downstream Power Benefits
for
Operating Year 1997-98



Columbia River Treaty Operating Committee

October 1992

COLUMBIA RIVER TREATY
HYDROELECTRIC OPERATING PLAN

ASSURED OPERATING PLAN
FOR OPERATING YEAR 1997-98

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HYDROELECTRIC OPERATING PLAN
ASSURED OPERATING PLAN
FOR OPERATING YEAR 1997-98

October 1992

1. Introduction

The treaty between Canada and the United States of America relating to the cooperative development of the water resources of the Columbia River Basin requires that each year an Assured Operating Plan be agreed to by the Entities for the operation of the Columbia River Treaty storage in Canada during the sixth succeeding year. This plan will provide to the Entities information for the sixth succeeding year for planning the power systems in their respective countries which are dependent on or coordinated with the operation of the Canadian storage projects.

This Assured Operating Plan was prepared in accordance with the Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans[1] and in accordance with the Entity Agreements on Principles[2] and on Changes to Procedures[3] for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies. It is based on criteria contained in Annex A and Annex B of the Columbia River Treaty,[4] Protocol,[5] Terms of Sale,[6] and the Columbia River Treaty Flood Control Operating Plan.[7]

The Assured Operating Plan consists of:

(a) The Operating Rule Curve for the whole of the Canadian storage, computed from the individual project Critical Rule Curves, Assured Refill Curves and Variable Refill Curves, and the individual project Upper Rule Curves.

(b) Operating Rules which specifically designate criteria for operation of the Canadian storage in accordance with the principles contained in the above references.

2. System Regulation Studies

In accordance with Annex A, Paragraph 7, of the Treaty, the Columbia River Treaty Operating Committee conducted system regulation studies reflecting Canadian storage operation for optimum generation in both Canada and the United States. Downstream power benefits were computed with the Canadian storage operation based on the operating rules specified herein. For this operation, there is a 2.8 MW decrease in the Canadian Entitlement to annual average usable energy and no change in the Entitlement to dependable capacity when compared to the operation for optimum generation in the United States alone. This is within the limits specified by the Treaty.

System Regulation Studies for the Assured Operating Plan were based on 1997-98 estimated loads and resources in the United Sates Pacific Northwest System and resources in the Columbia River Basin in British Columbia. The Entities have agreed that the 1997-98 Assured Operating Plan would be based on a 30-year streamflow period and an operating year of 1 August to 31 July. Historical flows for the period August 1928 through July 1958, modified by estimated irrigation depletions for 1980 level, were used.[8]

The Critical Rule Curves for these studies were determined from the Bonneville Power Administration Study of optimum power generation in both Canada and the United States. The study indicated a 42-month critical period for the United States system resulting from the low flows during the period from 1 September 1928 through 29 February 1932. With the exception of Brownlee, it was assumed that all reservoirs, both in the United States and Canada, were full at the beginning of the critical period except where minimum release requirements made this impossible.

In the studies, individual project flood control criteria were followed. Flood Control and Variable Refill Criteria are based on historical inflow volumes. Although only 7.0 million acre-feet of usable storage at Mica is committed for power operation purposes under the Treaty, the Columbia River Treaty Flood Control Operating Plan provides for the full draft of the total 12 million acre-feet of usable storage at Mica for on-call flood control purposes.

3. Development of the Assured Operating Plan

This Assured Operating Plan was developed in accordance with Annex A, paragraph 7 of the Treaty and therefore was designed to produce optimum power generation at-site in Canada and downstream in Canada and the United States. The Mica Operating criteria specified in Table 1 were evaluated using the two tests described below.

(a) Determination of Optimum Generation in Canada and the United States

To determine whether optimum generation in both Canada and the United States was achieved in the system regulation studies, the firm energy capability, dependable peaking capability and average annual usable secondary energy were computed for both the Canadian and United States systems.

In the studies for the 1997-98 Assured Operating Plan, the Canadian storage operation was operated to achieve a weighted sum of the three quantities that was greater than the weighted sum achieved under an operation of Canadian storage for optimum generation in the United States of America alone.

The Columbia River Treaty Operating Committee agreed that for the 1997-98 Assured Operating Plan the three quantities would be assigned the following relative values:

Quantity	Relative Value
Firm energy capability (Avg. MW)	3
Dependable peaking capability (MW)	1
Average annual usable secondary energy (Avg. MW)	2

The three quantities were added after weighting on this basis and there was a net gain to the combined Canadian and United States systems with the study designed for optimum generation in Canada and the United States.

Table 2 shows the results from studies adopted for the 1997-98 Assured Operating Plan and from studies designed to achieve optimum generation in the United States alone.

(b) Maximum Permitted Reduction in Downstream Power Benefits

Separate system regulation studies were developed reflecting (i) Canadian storage operation for optimum generation in both Canada and the United States, using the Mica Project operating criteria described in Section 5(c), and (ii) Canadian storage operation for optimum generation in the United States alone. For these Mica Project operating criteria, there is a 2.8 MW decrease in entitlement to average annual energy compared to an operation for optimum generation in the United States alone.

These changes are within the limits specified by the Treaty. The computations of these values are provided in the report Determination of Downstream Power Benefits for the Assured Operating Plan for 1997-98.

4. Operating Rule Curves

The operation of Canadian storage during the 1997-98 Operating Year shall be guided by an Operating Rule Curve for the whole of Canadian storage, Flood Control Storage Reservation Curves for the individual projects, and operating rules for specific projects. The Operating Rule Curve is derived from the various curves described below. These operating rule curves are first determined for the individual Canadian projects and then summed to yield the Composite Operating Rule Curve for the whole of Canadian storage. This is in accordance with the provision of Article VII(2) of the Protocol.

(a) Critical Rule Curve.

The Critical Rule Curve indicates the end-of-month storage content of Canadian storage during the critical period. It is designed to protect the ability of the United States system to serve firm load with the occurrence of flows no worse than those during the most adverse historical streamflow period. A tabulation of the Critical Rule Curves for Mica, Arrow and Duncan and the Composite Critical Rule Curve for the whole of Canadian storage are included in Table 3.

(b) Refill Curve

The Refill Curve is a guide to operation of Canadian storage which defines the normal limit of storage draft to produce secondary energy in order to provide a high probability of refilling the storage. In general, the Operating Plan does not permit serving secondary loads at the risk of failing to refill storage and thereby jeopardizing the firm load carrying capability of the United States or Canadian system during subsequent years. The end of the refill period is considered to be 31 July.

The Refill Curve is, in turn, defined by two curves as discussed below. In each case, adjustment should be made for water required for refill of upstream reservoirs when applicable.

(1) Assured Refill Curve.

The Assured Refill Curve indicates the end-of-month storage content required to assure refill of Canadian storage based on the 1930-31 water year, the system's second lowest historical volume of inflow during the 30-year record for the period

January through July as measured at The Dalles, Oregon. A tabulation of the Assured Refill Curves for Mica, Arrow and Duncan is included as Table 4.

The schedule of outflows used in developing these Assured Refill Curves is shown in Tables 5 - 7. These outflows are not the same as the Power Discharge Requirements used in computing the Variable Refill Curve.

(2) Variable Refill Curve.

The Variable Refill Curves give end-of-month storage contents for the period January through July required to refill Canadian storage during the refill period. They were based on historical inflow volumes and Power Discharge Requirements determined in accordance with the Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans.[1] In the system regulation studies the Power Discharge Requirement was made a function of the natural January - July runoff volume at The Dalles, Oregon. The Power Discharge Requirement used in computing the Variable Refill Curves was interpolated linearly between the values shown in Tables 5 - 7. In those years when the January to July runoff volume at The Dalles was less than 80 million acre-feet or greater than 110 million acre-feet, the discharge used was that specified for 80 and 110 million acre-feet, respectively.

Variable Refill Curves for Mica, Arrow and Duncan for the 30 years of historical record are recorded in Tables 5 - 7. These illustrate the probable range of these curves based on historical conditions. In actual operation in 1997-98, the Power Discharge Requirements will be based on the forecast of unregulated runoff at The Dalles.

(c) Limiting Rule Curve.

The Limiting Rule Curves indicate month-end storage contents which must be maintained to guarantee the system meeting its firm load during the period 1 January - 31 March in the event that the Variable Refill Curves permit storage to be emptied and sufficient natural flow is not available to carry the load prior to the start of the freshet. Such rule curves shall limit the Variable Refill Curve to be no lower than the Limiting Rule Curve. The Limiting Rule Curve is developed for 1936-37 water conditions. Limiting Rule Curves for Mica, Arrow and Duncan are shown in Tables 5 - 7.

(d) Upper Rule Curve.

The Upper Rule Curves [7] indicate the end-of-month storage content to which each individual Canadian storage project shall be evacuated for flood control and other requirements. The Upper Rule Curves used in the studies were based upon Flood Control Storage Reservation Diagrams contained in the Columbia River Treaty Flood Control Operating Plan and analysis of system flood control simulations. Flood control curves for Mica, Arrow and Duncan for the 30-year study period are shown on Tables 8 - 10. Tables 9 and 10 reflect an agreed transfer of 2 million acre-feet of flood control storage space from Arrow to Mica. In actual operation, the Flood Control Storage Reservation Curves will be computed as outlined in the Flood Control Operating Plan, using the latest forecast of runoff available at that time.

(e) Definition of Operating Rule Curve

During the period 1 August through 31 December, the Operating Rule Curve is defined by the Critical Rule Curve or the Assured Refill Curve, whichever is higher. The Critical Rule Curve for the first year of the critical period is used in the foregoing determination. During the period 1 January through 31 July, the Operating Rule Curve is defined by the higher of the Critical Rule Curve and the Assured Refill Curve; unless the Variable Refill Curve is lower than this value, then it is defined by the Variable Refill Curve. During the period 1 January through 31 March, it will not be lower than the Limiting Rule Curve. The Operating Rule Curve meets all requirements for flood control operation. Composite Operating Rule Curves for the whole of Canadian storage for all 30 years of historical record are included as Table 11 to illustrate the probable future range of these curves based on historical conditions.

5. Operating Rules

A 30-year System Regulation Study[10] was utilized to develop and test the operating rules and rule curves. It contains the agreed-upon operating constraints such as maximum and minimum project elevations, discharges, draft rates, etc. These constraints are included as part of this operating plan.

The following rules, used in the 30-year System Regulation Study[10], will apply to the operation of Canadian storage in the 1997-98 Operating Year.

(a) Operation Above Operating Rule Curve

The whole of the Canadian storage will be drafted to its Operating Rule Curve as required to produce optimum generation in Canada and the United States in accordance with Annex A, Paragraph 7, of the Treaty, subject to project physical characteristics, operating constraints, and the criteria for the Mica project listed in 5(c).

(b) Operation Below Operating Rule Curve

The whole of Canadian storage will be drafted below its Operating Rule Curve as required to produce optimum generation to the extent that a System Regulation Study determines that proportional draft below the Operating Rule Curves/Energy Content Curves is required to produce the hydro firm energy load carrying capability of the United States system as determined by the applicable Critical Period Regulation study. Energy Content Curves for United States reservoirs are equivalent to Operating Rule Curves. Proportional draft between rule curves will be determined as described in the Principles and Procedures.[1]

However, Mica Reservoir will continue to be operated in accordance with 5(c), so as to optimize generation at site and at Revelstoke as well as downstream in the United States. In the event the Mica operation results in more or less than the project's proportional share of draft from the whole of Canadian storage, compensating drafts will be made from Arrow to the extent possible.

(c) Mica Project Operation

Mica project operation will be determined by the end of previous period Arrow storage content as shown in Table 1. Mica monthly outflows will be increased above the values shown in the table in the months from October through June if required to avoid violation of the Upper Rule Curve.

Under this Assured Operating Plan, Mica storage releases in excess of 7 million acre-feet that are required to maintain the Mica outflows specified under this plan will be retained in the Arrow reservoir, subject to flood control and other project operating criteria at Arrow. The total combined storage draft from Mica and Arrow will not exceed 14.1 million acre-feet unless flood control criteria will not permit the additional Mica storage releases to be retained at Arrow. Should storage releases in excess of 14.1 million acre-feet be made, the target Mica operation will remain as specified in Table 1.

Revelstoke, Upper Bonnington, Lower Bonnington, South Slocan, Brilliant, Seven Mile and Waneta have been included in the 1997-98 Assured Operating Plan and have been operated as run-of-river projects. Corra Linn and Kootenay canal were also included in the study and operated in accordance with International Joint Commission rules for Kootenay Lake.

6. Implementation

The Entities have agreed that each year a Detailed Operating Plan will be prepared for the immediately succeeding operating year. Such Detailed Operating Plans are made under authority of Article XIV 2.(k) of the Columbia River Treaty which states:

"...the powers and the duties of the entities include:

(k) preparation and implementation of detailed operating plans that may produce results more advantageous to both countries than those that would arise from operation under the plans referred to in Annexes A and B."

The Detailed Operating Plan for 1997-98 will reflect the latest available load, resource, and other pertinent data to the extent the Entities agree these data should be included in the plan.

The operating rules to be used in implementation of the Detailed Operating Plan for 1997-98 are generally the same as the operating rules described in this document. The data and criteria contained herein may be reviewed, and updated as agreed by the Entities, to form the basis for a Detailed Operating Plan for 1997-98. Failing agreement on updating the data and/or criteria, the Detailed Operating Plan for 1997-98 will include the rule curves, Mica operating criteria, and other data and criteria provided in this Assured Operating Plan. Actual operation during the 1997-98 Operating Year shall be guided by the Detailed Operating Plan.

The values used in the Assured Operating Plan studies to define the various rule curves were month-end values only. In actual operation, it is necessary to operate in such a manner during the course of each month that these month-end values can be observed in accordance with the operating rules. Because of the normal variation of power load and streamflow during any month, straight line interpolation between the month-end points should not be assumed.

During the storage drawdown season, Canadian storage should not be drafted below its month-end point at any time during the month unless it can be conservatively demonstrated that sufficient inflow is available, in excess of the minimum outflow required to serve power demand, to refill the reservoir to its end-of-month value as required. During the storage evacuation and refill season, operation will be consistent with the Flood Control Operating Plan. When refill of Canadian storage is being guided by Flood Control Refill Curves,[7] such curves will be computed on a day-by-day basis using the residual volume-of-inflow forecasts depleted by the volume required for minimum outflow from each day through the end of the refill season.

7. Delivery of Canadian Entitlement

On 1 April 1998, the portion of the Canadian Entitlement to downstream power benefits related to the operation of Duncan dam cease to be covered by the Terms of the Sale of the Canadian Entitlement in the United States of America authorized by an Exchange of Notes between Canada and the United States of America dated 16 September 1964 [11]. Since no further sale has been authorized by Canada and the United States, this Assured Operating Plan has been prepared on the basis that the portion of the Canadian Entitlement attributable to Duncan will be returned to Canada, starting 1 April 1998.

The Treaty specifies return of the Canadian Entitlement at a point near Oliver, British Columbia unless otherwise agreed by the Entities. Because no cross border transmission exists at any point on the Canada-United States of America boundary near Oliver, the Entities completed an agreement on Aspects of the Canadian Entitilement Return for April 1 1998 through March 31, 2003, executed 28 July 1992. This agreement describes the existing points of interconnection. The Entities have agreed that delivery of 50 % of the Canadian Entitlement attributable to Duncan, net of 3% transmission loss, will be delivered at the Nelway Point of delivery and the Waneta Point of Delivery. The other 50% of the Canadian Entitlement attributable to Duncan, net of 3% transmission loss, will be delivered at the Blaine No. 1 Point of delivery and the Blaine No. 2 Point of Delivery. These arrangements cover the 1 April 1998 through 31 July, 1998 period that falls within the period covered by this Assured Operating Plan.

8. Capacity/Energy Entitlement Scheduling Guidelines

The Entities developed scheduling guidelines for return of the Canadian Entitlement attributable to Duncan storage for the period 1 April 1998 through 31 July 1998. In developing the scheduling guidelines, the Entities recognized there was a logical linkage between the rights of the U.S. Entity to schedule water discharges from Treaty storage and the rights of the Canadian Entity to schedule Entitlement power. As the Entities acquire experience under the annual scheduling guidelines, mutually agreed modifications and clarifications to the scheduling guidelines will be included in future AOP's. The 1997-98 scheduling guidelines follow:

(a) The Canadian Entitlement Return (CER), daily schedules which satisfy monthly energy and capacity obligations, shall be finalized by the Canadian Section of the Operating Committee and submitted to the U.S. Section of the Operating Committee during a weekly telephone conference call at 11:00 a.m. on the working day prior to the last working day of each week. In addition, the U.S. Section shall provide its preliminary

Treaty project weekly flow request for the following Saturday through Friday period. The Treaty project weekly flow request shall be confirmed and finalized not later than 11:00 a.m. on the last working day of each week. The U.S. Section shall make reasonable efforts not to change the weekly flow request.

(b) Capacity/Energy schedules submitted by the Canadian Section shall not be changed except as may be necessary due to outage or emergency conditions on the generating or transmission systems of either the Canadian or U.S. Sections.

(c) The following procedures will be used when scheduling energy and capacity unless otherwise mutually agreed:

Deliveries on any hour shall not exceed the hourly capacity obligation.

Deliveries on light load hours shall be delivered in equal hourly amounts.

The total monthly energy obligation shall be deemed delivered to BCH by the end of the month.

The average energy delivered during any day shall not exceed 1.5 times the daily average energy obligation for the month.

Heavy load hours consist of hour ending (HE) 0800 through HE 2200 Pacific Standard Time (PST) or Daylight Saving Time (DST) Monday through Saturday.

Light load hours consist of all other hours.

There are no exceptions to the definitions of heavy load and light load hours; that is, it does not matter whether the day is a normal working day or a holiday.

(d) CER power required to be delivered to the Canadian Section not delivered due to emergency forced outages of transmission and generation equipment or facilities shall be delivered within the seven days following the outage at times and rates determined by current CER limits unless otherwise mutually agreed. If the full monthly energy obligation has been delivered, no further CER schedules for capacity or energy will occur during that month, unless otherwise agreed.

For the 1997-98 scheduling guidelines, the Canadian Entity has agreed to a daily energy Entitlement scheduling limit of 1.5 times the average monthly energy. In consideration, the U.S. Entity agrees to accept a reduction of the Arrow lakes maximum daily average discharge rate-of-change from 25 to 15 kcfs in the 1997-98 Detailed Operating Plan.

REFERENCES

1 Columbia River Treaty Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans, Columbia River Treaty Operating Committee, dated December 1991.

2 Columbia River Treaty Entity Agreement on Principles for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies, dated 28 July 1988.

3 Columbia River Treaty Entity Agreement on Changes to Procedures for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies, dated 12 August 1988.

4 Treaty between the United States of America and Canada relating to Cooperative Development of the Water Resources of the Columbia River Basin, dated 17 January 1961.

5 Protocol - Annex to Exchange of Notes, dated 22 January 1964.

6 Attachment Relating to Terms of Sale - Attachment to Exchange of Notes, dated 22 January 1964.

7 Columbia River Treaty Flood Control Operating Plan, dated October 1972.

8 Report on 1980 Level Modified Streamflows, 1928 to 1978, Columbia River and Coastal Basins, Columbia River Water Management Group, dated July 1983.

9 Summary of End-of-Month Reservoir Storage Requirement from Columbia River Flood Regulation Studies, dated April 1973 and as updated March 1975.

10 BPA Hydroelectric Power Planning Program, Assured Operating Plan 30-year System Regulation Study 98-41, dated 21 September 1992.

11 Exchange of notes - Regarding the Disposal of the Canadian Entitlement to Downstream Power Benefits, dated 16 September 1964.

TABLE 1
MICA PROJECT OPERATING CRITERIA
ASSURED OPERATING PLAN

Month	End of Previous Period Arrow Storage Content (ksfd)	----- Target Operation --------- Period Average Outflow (cfs)	End-of-Period Treaty Content[1] (ksfd)	Minimum Outflow (cfs)	Min Treaty Target Content[2] (ksfd)
August 1-15	1 300 - FULL	-	3 456.2	10 000	0.0
	0 -1 300	27 000			
August 16-31	3 400 - FULL	-	3 529.2	10 000	0.0
	800 -3 400	28 000			
	0 - 800	30 000			
September	3 340 - FULL	-	3 529.2	10 000	0.0
	900 -3 340	22 000			
	0 - 900	32 000			
October	3 260 - FULL	15 000		10 000	0.0
	2 400 -3 260	23 000			
	0 -2 400	32 000			
November	3 340 - FULL	19 000	-	10 000	0.0
	2 300 -3 340	24 000			
	0 -2 300	32 000			
December	3 200 - FULL	23 000	-	15 000	0.0
	2 300 -3 200	28 000			
	0 -2 300	30 000			
January	2 320 - FULL	24 000	-	15 000	0.0
	1 250 -2 320	27 000			
	0 -1 250	30 000			
February	1 284 - FULL	22 000	-	15 000	106.2
	1 100 -1 284	25 000			
	0 -1 100	29 000			
March	1 220 - FULL	19 000	-	15 000	0.0
	1 000 -1 220	26 000			
	0 -1 000	28 000			
April 1-15	0 - FULL		106.2	15 000	0.0
April 16-30	0 - FULL	-	0.0	10 000	0.0
May	0 - FULL	10 000	-	10 000	0.0
June	450 - FULL	10 000	-	10 000	0.0
	0 - 450	21 000			
July	2 300 - FULL	-	3 356.2	10 000	0.0
	720 -2 300	20 000			
	0 - 720	25 000			

Notes:

1/ A maximum outflow of 34000 cfs will apply if the target end-of-period storage content is less than 3529.2 ksfd except a maximum outflow of 32 000 cfs will apply from April 1-15, a maximum outflow of 27 000 cfs will apply from April 16-30 and a maximum outflow of 30 000 cfs will apply in May.

2/ Mica outflows will be reduced to minimum to maintain the reservoir above the minimum Treaty storage content. This will override any target flow.

TABLE 2

COMPARISON OF ASSURED OPERATING PLAN STUDY RESULTS

Study 98-41 provides Optimum Generation in Canada and in the United States.
Study 98-11 provides Optimum Generation in the United States only.

	Study No. 98-41	Study No. 98-11	Net Gain	Weight	Value
1. Firm Energy Capability (Avg. MW)					
U.S. System[1]	12,224.0	12,224.9	-0.9		
Canada[2,3]	2,811.7	2,765.0	+46.7		
Total	15,035.7	14,989.9	+45.8	3	+137.4
2. Dependable Peaking Capacity (MW)					
U.S. System[4]	31,379.0	31,383.0	-4.0		
Canada[2,5]	5,366.0	5,347.0	+19.0		
Total	36,745.0	36,730.0	+15.0	1	+15.0
3. Average Annual Usable Secondary Energy (Avg. MW)					
U.S. System[6]	3,019.5	3,005.6	+13.9		
Canada[2,7]	215.6	259.1	-43.5		
Total	3,235.1	3,264.7	-29.6	2	-59.2
			Net Change in Value =		+ 93.2

Notes:

1/ U.S. System firm energy capability was determined over the U.S. system critical period beginning 1 September 1928 and ending 29 February 1932.

2/ Canadian system includes Mica, Revelstoke, Canal, Corra Linn, Upper Bonnington, Lower Bonnington, South Slocan, Brilliant, Seven Mile and Waneta.

3/ Canadian system firm energy capability was determined over the Canadian system critical period beginning 1 October 1940 and ending 30 April 1946.

4/ U.S. system dependable peaking capability was determined from January 1937.

5/ Canadian system dependable peaking capability was determined from December 1944.

6/ U.S. system 30-year average secondary energy limited to secondary market.

7/ Canadian system 30-year average generation minus firm energy capability.

TABLE 3

COLUMBIA RIVER TREATY
CRITICAL RULE CURVES
END OF MONTH CONTENTS IN KSFD
1997-98 OPERATING YEAR

MICA

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1ST YR	3529.2	3529.2	3343.6	3348.5	3078.2	2516.2	1914.0	1376.8	821.5	252.2	0.0	461.0	2109.5	3091.1
2ND YR	3042.2	3085.5	3085.5	3099.2	2172.5	1759.9	902.1	644.0	144.9	0.0	39.5	456.2	1537.4	2753.9
3RD YR	2956.2	3067.7	3248.0	2937.2	2063.5	1333.3	739.9	407.5	0.0	0.0	0.0	287.7	1433.5	2381.5
4TH YR	2381.4	2381.3	2005.4	1243.4	122.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

ARROW

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1ST YR	3579.6	3579.6	3449.0	3301.6	3214.2	2806.6	1620.6	662.3	517.2	385.2	69.7	775.2	2318.2	3220.3
2ND YR	3496.0	3250.2	3280.1	2777.9	2425.6	1917.8	1042.5	197.5	6.5	6.6	376.4	622.1	1369.9	2784.9
3RD YR	3106.1	3066.6	3018.8	2654.2	2417.4	1739.0	989.4	132.7	10.0	10.3	10.5	277.3	625.2	895.9
4TH YR	826.9	697.8	826.9	882.9	1174.3	382.4	5.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0

DUNCAN

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1ST YR	705.8	705.8	705.8	647.3	600.0	433.0	297.2	185.6	124.6	41.3	17.2	134.5	409.3	552.0
2ND YR	566.5	614.6	471.2	282.0	227.4	197.2	60.0	59.0	0.0	0.0	0.0	107.9	212.4	335.0
3RD YR	282.3	321.7	207.8	138.6	118.0	80.6	58.9	58.0	0.0	0.0	0.0	5.3	104.6	120.0
4TH YR	130.0	81.0	2.0	37.0	58.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

COMPOSITE

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1ST YR	7814.6	7814.6	7498.4	7297.4	6892.4	5755.8	3831.8	2224.7	1463.3	678.7	86.9	1370.7	4837.0	6863.4
2ND YR	7104.7	6950.3	6836.8	6159.1	4825.5	3874.9	2004.6	900.5	151.4	6.6	415.9	1186.2	3119.7	5873.8
3RD YR	6344.6	6456.0	6474.6	5730.0	4598.9	3152.9	1788.2	598.2	10.0	10.3	10.5	570.3	2163.3	3397.4
4TH YR	3338.3	3160.1	2834.3	2163.3	1354.8	382.4	5.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0

TABLE 4

COLUMBIA RIVER TREATY
ASSURED REFILL CURVES
END OF MONTH CONTENTS IN KSFD
1997-98 OPERATING YEAR

MICA

AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1143.2	1726.5	2329.5	2507.8	2573.0	2589.5	2584.3	2096.9	1576.6	1346.8	1125.2	1313.7	2460.0	3529.2

ARROW

AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
0.0	0.0	0.0	0.0	0.0	21.4	72.3	583.9	1187.7	1203.0	1357.2	2038.6	3136.3	3579.6

DUNCAN

AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
10.4	81.3	147.6	178.3	195.8	207.0	217.2	218.0	222.8	231.5	231.2	345.0	540.9	705.8

TABLE 5

DUNCAN VARIABLE REFILL CURVE (KSFD)
1997-98 OPERATING YEAR

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29							480.4	445.5	421.0	414.7	411.5	441.5	589.0	705.8
1929-30							478.7	443.5	418.7	412.0	422.9	462.2	600.4	,,
1930-31							423.3	389.3	368.0	366.5	369.8	411.1	589.0	,,
1931-32							0.0	0.0	0.0	0.0	0.0	109.6	442.3	,,
1932-33							,,	,,	,,	,,	,,	0.0	307.9	,,
1933-34							,,	,,	,,	,,	,,	141.5	483.0	,,
1934-35							64.2	52.7	58.7	65.4	88.5	202.5	462.1	,,
1935-36							63.9	42.9	34.6	37.3	59.9	198.9	509.1	,,
1936-37							427.6	392.7	370.1	363.6	361.5	403.3	571.1	,,
1937-38							0.0	0.0	0.0	0.0	17.6	164.8	466.4	,,
1938-39							275.7	247.2	227.9	225.4	239.2	323.1	571.9	,,
1939-40							259.8	235.6	223.7	231.0	246.2	325.2	560.5	,,
1940-41							340.3	314.1	298.3	306.9	329.3	402.4	584.1	,,
1941-42							176.3	167.2	168.0	175.4	198.6	300.3	529.3	,,
1942-43							81.1	76.1	86.1	96.7	136.0	276.6	499.8	,,
1943-44							497.4	466.9	447.3	443.0	441.4	474.6	619.1	,,
1944-45							408.9	380.8	363.0	359.5	357.8	399.3	575.1	,,
1945-46							0.0	0.0	0.0	0.0	0.0	54.6	435.3	,,
1946-47							,,	,,	,,	,,	,,	97.8	448.1	,,
1947-48							,,	,,	,,	,,	,,	115.9	459.0	,,
1948-49							135.8	127.4	134.0	142.0	172.4	289.8	560.6	,,
1949-50							0.0	0.0	0.0	0.0	0.0	124.0	402.7	,,
1950-51							,,	,,	,,	,,	,,	89.9	433.9	,,
1951-52							,,	,,	,,	,,	22.2	174.9	479.2	,,
1952-53							,,	,,	,,	,,	19.5	153.4	445.3	,,
1953-54							,,	,,	,,	,,	0.0	17.1	376.0	,,
1954-55							,,	,,	,,	,,	,,	106.7	381.8	,,
1955-56							,,	,,	,,	,,	,,	64.5	431.9	,,
1956-57							,,	,,	,,	,,	,,	116.8	496.2	,,
1957-58							,,	,,	,,	,,	,,	54.9	448.1	,,
ECC LOWER LIMIT							0.0	0.0	0.0					

		JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
POWER DISCHARGE REQUIREMENTS IN CFS FOR	80 MAF--	100	1000	1000	1000	2000	2000	2000	2000
JANUARY - JULY, VOLUME RUNOFF AT THE DALLES	95 MAF--	100	100	100	100	100	100	100	100
FOR VARIABLE REFILL CALCULATION	110 MAF--	100	100	100	100	100	100	100	100
FOR ASSURED REFILL CALCULATION		100	400	400	400	1000	1500	1500	2000

TABLE 6

ARROW VARIABLE REFILL CURVE (KSFD)
1997-98 OPERATING YEAR

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29							1705.6	1801.3	2056.1	2094.0	2492.1	2656.3	3350.0	3579.6
1929-30							1185.9	308.9	568.6	639.0	1279.5	2066.6	3153.9	,,
1930-31							,,	624.5	903.7	963.9	1453.0	1876.4	3152.9	,,
1931-32							,,	308.9	0.0	0.0	0.0	986.4	2745.7	,,
1932-33							,,	,,	,,	,,	297.9	1283.8	2761.4	,,
1933-34							,,	,,	,,	,,	93.2	1861.7	3293.8	,,
1934-35							,,	,,	,,	,,	248.4	1094.3	2571.4	,,
1935-36							,,	,,	,,	,,	0.0	1064.3	3092.8	,,
1936-37							2040.3	2083.0	2337.5	2335.1	2741.5	2853.4	3448.0	,,
1937-38							1185.9	340.3	334.8	392.8	775.3	1671.3	3046.2	,,
1938-39							,,	441.5	729.3	787.9	1364.2	1980.8	3509.4	,,
1939-40							,,	308.9	329.8	496.8	1146.6	1767.3	3232.7	,,
1940-41							,,	1312.1	1630.0	1805.1	2502.9	2931.0	3579.6	,,
1941-42							,,	571.3	976.4	1096.7	1675.0	2267.7	3295.7	,,
1942-43							1900.7	1764.2	1726.2	1717.3	2160.1	3266.5	3579.6	,,
1943-44							2556.7	2647.6	2925.0	2932.7	3340.3	3419.6	,,	,,
1944-45							1861.6	2005.3	2322.5	2386.2	2766.6	2871.1	,,	,,
1945-46							1185.9	308.9	0.0	0.0	438.8	1490.8	3067.5	,,
1946-47							,,	,,	110.8	155.7	578.3	1564.1	3009.6	,,
1947-48							,,	,,	278.7	263.4	609.1	1578.6	3076.7	,,
1948-49							,,	,,	732.3	926.7	1580.9	2559.3	3579.6	,,
1949-50							,,	,,	205.8	242.4	595.6	1506.4	2747.8	,,
1950-51							,,	559.0	568.9	570.5	951.3	1864.5	3258.6	,,
1951-52							,,	568.5	561.1	569.7	897.2	1984.3	3369.1	,,
1952-53							,,	620.1	613.6	622.8	1072.2	2034.1	3203.5	,,
1953-54							,,	308.9	0.0	0.0	214.7	1190.6	2742.0	,,
1954-55							,,	,,	,,	,,	36.8	961.8	2271.1	,,
1955-56							,,	,,	,,	13.8	398.7	1556.5	3062.2	,,
1956-57							,,	,,	,,	15.0	403.9	1386.8	3458.8	,,
1957-58							,,	,,	,,	0.0	178.7	1162.8	3034.1	,,
ECC LOWER LIMIT							1185.9	308.9	0.0					

		JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
POWER DISCHARGE REQUIREMENTS IN CFS FOR	80 MAF--	5000	10000	10000	15000	15000	30000	30000	30000
JANUARY - JULY, VOLUME RUNOFF AT THE DALLES	95 MAF--	5000	5000	5000	5000	5000	15000	25000	25000
FOR VARIABLE REFILL CALCULATION	110 MAF--	5000	5000	5000	5000	5000	8000	35000	35000
FOR ASSURED REFILL CALCULATION		5000	5000	5000	25000	25000	40000	40000	40000

TABLE 7

MICA VARIABLE REFILL CURVE (KSFD)
1997-98 OPERATING YEAR

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29							3529.2	3529.2	3381.0	3180.1	3010.7	2599.0	2985.1	3529.2
1929-30							3206.8	2725.6	2307.1	2125.7	2088.1	1986.4	2701.1	,,
1930-31							3466.0	2993.8	2571.1	2367.6	2260.8	2006.6	2776.1	,,
1931-32							698.4	478.0	433.4	392.3	504.5	1081.6	2413.6	,,
1932-33							,,	357.6	330.3	283.5	379.2	943.1	2232.7	,,
1933-34							,,	187.4	0.0	0.0	0.0	643.0	2461.8	,,
1934-35							1908.9	1664.7	1504.0	1428.9	1396.8	1537.0	2477.4	,,
1935-36							2003.6	1704.4	1477.8	1356.4	1331.2	1547.1	2759.2	,,
1936-37							3529.2	3529.2	3334.2	3122.4	3001.4	2612.8	3017.5	,,
1937-38							888.2	776.1	731.8	695.1	789.9	1308.9	2506.3	,,
1938-39							3271.0	2867.2	2458.3	2280.9	2196.0	2030.3	3009.0	,,
1939-40							3062.8	2610.2	2218.2	2035.0	1972.4	1823.2	2768.8	,,
1940-41							3529.2	3197.7	2794.7	2610.4	2584.5	2386.9	2999.0	,,
1941-42							2456.0	2206.3	2014.3	1907.0	1870.1	1968.9	2809.8	,,
1942-43							1345.8	1211.5	1169.7	1111.5	1282.6	1838.5	2692.2	,,
1943-44							3529.2	3529.2	3439.4	3230.7	3087.7	2719.9	3156.0	,,
1944-45							,,	,,	3360.4	3175.1	3019.1	2629.7	3069.4	,,
1945-46							698.4	187.4	0.0	0.0	19.2	680.4	2360.0	,,
1946-47							,,	335.9	318.3	286.8	412.3	1043.1	2478.8	,,
1947-48							,,	187.4	51.3	0.0	102.2	731.6	2313.0	,,
1948-49							2206.3	2071.6	2013.6	1974.2	2012.9	2303.5	3177.5	,,
1949-50							698.4	401.9	345.6	281.4	400.2	956.1	2124.7	,,
1950-51							,,	442.6	418.4	371.7	517.5	1077.6	2486.6	,,
1951-52							946.8	802.9	753.8	683.2	792.1	1372.5	2633.4	,,
1952-53							1416.7	1290.7	1251.3	1205.1	1257.1	1638.4	2655.2	,,
1953-54							698.4	187.4	0.0	0.0	48.4	647.3	2096.8	,,
1954-55							1397.1	1290.3	1257.2	1237.2	1271.5	1586.8	2434.7	,,
1955-56							698.4	300.2	255.8	194.1	318.3	974.6	2401.6	,,
1956-57							,,	461.9	432.2	382.5	504.1	1061.7	2731.6	,,
1957-58							,,	456.5	433.1	398.5	515.1	1044.0	2538.0	,,
ECC LOWER LIMIT							698.4	187.4	0.0					

POWER DISCHARGE REQUIREMENTS IN CFS FOR	80 MAF--	3000	15000	15000	15000	20000	30000	30000	25000
JANUARY - JULY, VOLUME RUNOFF AT THE DALLES	95 MAF--	3000	3000	3000	3000	10000	10000	20000	20000
FOR VARIABLE REFILL CALCULATION	110 MAF--	3000	3000	3000	5000	5000	5000	15500	15500
FOR ASSURED REFILL CALCULATION		3000	20000	20000	20000	22000	22000	22000	22000

TABLE 8

DUNCAN
FLOOD CONTROL STORAGE RESERVATION CURVES
1997-98 OPERATING YEAR
KSFD

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	705.8	705.8	705.8	705.8	705.8	504.1	418.3	340.8	340.8	348.1	360.5	443.7	574.4	705.8
1929-30	,,	,,	,,	,,	,,	,,	408.4	322.1	322.1	329.8	342.9	430.3	567.7	,,
1930-31	,,	,,	,,	,,	,,	,,	391.0	288.9	288.9	297.2	311.4	406.4	555.7	,,
1931-32	,,	,,	,,	,,	,,	,,	277.3	65.5	65.5	80.9	109.1	281.3	609.8	,,
1932-33	,,	,,	,,	,,	,,	,,	273.7	,,	,,	75.1	94.3	191.7	573.3	,,
1933-34	,,	,,	,,	,,	,,	,,	,,	,,	,,	65.5	127.0	339.6	605.3	,,
1934-35	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	83.5	187.2	488.1	,,
1935-36	,,	,,	,,	,,	,,	,,	277.3	,,	,,	71.3	119.3	351.7	705.8	,,
1936-37	,,	,,	,,	,,	,,	,,	377.7	263.6	263.6	272.5	287.5	388.3	546.6	,,
1937-38	,,	,,	,,	,,	,,	,,	293.0	102.3	102.3	113.2	119.2	245.3	551.9	,,
1938-39	,,	,,	,,	,,	,,	,,	288.0	92.7	92.7	109.3	132.6	399.3	705.8	,,
1939-40	,,	,,	,,	,,	,,	,,	303.2	115.4	115.4	127.2	150.9	410.6	,,	,,
1940-41	,,	,,	,,	,,	,,	,,	345.5	202.1	202.1	212.2	229.3	344.2	524.5	,,
1941-42	,,	,,	,,	,,	,,	,,	328.5	169.9	169.9	179.0	201.5	326.4	501.6	,,
1942-43	,,	,,	,,	,,	,,	,,	333.0	178.4	178.4	192.2	221.1	289.2	653.1	,,
1943-44	,,	,,	,,	,,	,,	,,	416.4	334.7	334.7	342.1	354.7	439.4	572.2	,,
1944-45	,,	,,	,,	,,	,,	,,	384.9	277.3	277.3	278.6	279.4	382.3	580.3	,,
1945-46	,,	,,	,,	,,	,,	,,	273.7	65.5	65.5	75.7	95.6	322.3	647.5	,,
1946-47	,,	,,	,,	,,	,,	,,	,,	,,	,,	77.1	102.0	314.0	629.6	,,
1947-48	,,	,,	,,	,,	,,	,,	277.3	,,	,,	65.5	65.5	300.5	705.8	,,
1948-49	,,	,,	,,	,,	,,	,,	371.1	251.0	251.0	256.9	277.0	434.3	,,	,,
1949-50	,,	,,	,,	,,	,,	,,	273.7	65.5	65.5	65.5	65.5	184.0	525.3	,,
1950-51	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	285.1	534.2	,,
1951-52	,,	,,	,,	,,	,,	,,	277.3	,,	,,	,,	67.4	92.4	255.0	,,
1952-53	,,	,,	,,	,,	,,	,,	273.7	,,	,,	71.9	84.7	234.6	522.7	,,
1953-54	,,	,,	,,	,,	,,	,,	,,	,,	,,	73.2	84.1	237.1	547.6	,,
1954-55	,,	,,	,,	,,	,,	,,	,,	,,	,,	71.9	80.9	154.5	488.8	,,
1955-56	,,	,,	,,	,,	,,	,,	277.3	,,	,,	65.5	84.7	266.6	585.4	,,
1956-57	,,	,,	,,	,,	,,	,,	273.7	,,	,,	74.5	89.9	376.1	655.8	,,
1957-58	,,	,,	,,	,,	,,	,,	,,	,,	,,	77.1	96.3	359.4	705.8	,,

TABLE 9

ARROW
FLOOD CONTROL STORAGE RESERVATION CURVES
1997-98 OPERATING YEAR
KSFD

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	3579.6	3579.6	3579.6	3453.6	3453.6	3075.4	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	3579.6	3579.6
1929-30	,,	,,	,,	,,	,,	,,	2998.3	2928.3	2851.2	2870.1	2902.9	3082.8	,,	,,
1930-31	,,	,,	,,	,,	,,	,,	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	,,	,,
1931-32	,,	,,	,,	,,	,,	,,	2371.6	1712.7	1008.4	1016.1	1126.6	2224.6	,,	,,
1932-33	,,	,,	,,	,,	,,	,,	2363.5	1720.2	,,	1008.4	1036.6	1761.7	3034.5	,,
1933-34	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	1784.9	2327.4	3579.6	,,
1934-35	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	1008.4	1725.7	3034.5	,,
1935-36	,,	,,	,,	,,	,,	,,	2371.6	1712.7	,,	1070.1	1373.5	2134.6	3579.6	,,
1936-37	,,	,,	,,	,,	,,	,,	2940.8	2818.8	2684.1	2707.4	2755.8	3266.2	,,	,,
1937-38	,,	,,	,,	,,	,,	,,	2363.5	1720.2	1008.4	1082.9	1278.3	1831.2	3147.6	,,
1938-39	,,	,,	,,	,,	,,	,,	2584.5	2141.3	1650.3	1719.8	1843.3	2661.3	3579.6	,,
1939-40	,,	,,	,,	,,	,,	,,	2793.4	2529.4	2247.3	2287.2	2380.5	2913.4	,,	,,
1940-41	,,	,,	,,	,,	,,	,,	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	,,	,,
1941-42	,,	,,	,,	,,	,,	,,	2363.5	1720.2	1008.4	1064.9	1149.8	1934.0	,,	,,
1942-43	,,	,,	,,	,,	,,	,,	,,	,,	,,	1111.2	1322.0	1440.3	2389.1	,,
1943-44	,,	,,	,,	,,	,,	,,	3075.4	3075.4	3075.4	3088.5	3111.2	3235.8	3579.6	,,
1944-45	,,	,,	,,	,,	,,	,,	2582.9	2138.0	1645.5	1672.5	1744.1	2368.8	3347.5	,,
1945-46	,,	,,	,,	,,	,,	,,	2363.5	1720.2	1008.4	1072.6	1242.3	2201.4	3579.6	,,
1946-47	,,	,,	,,	,,	,,	,,	,,	,,	,,	1075.2	1360.6	2147.4	,,	,,
1947-48	,,	,,	,,	,,	,,	,,	2371.6	1712.7	,,	1036.6	1183.2	2216.8	,,	,,
1948-49	,,	,,	,,	,,	,,	,,	2363.5	1720.2	,,	1144.6	1376.0	2494.5	,,	,,
1949-50	,,	,,	,,	,,	,,	,,	,,	,,	,,	1008.4	1008.4	1113.8	2232.3	,,
1950-51	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	1355.5	3337.9	,,
1951-52	,,	,,	,,	,,	,,	,,	2371.6	1712.7	,,	1070.1	1345.2	1792.6	3013.9	,,
1952-53	,,	,,	,,	,,	,,	,,	2363.5	1720.2	,,	1057.2	1172.9	1476.3	,,	,,
1953-54	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	1134.3	1628.0	1898.0	,,
1954-55	,,	,,	,,	,,	,,	,,	,,	,,	,,	1075.2	1090.6	1653.7	3224.8	,,
1955-56	,,	,,	,,	,,	,,	,,	2371.6	1712.7	,,	1008.4	1216.6	1990.6	2993.4	,,
1956-57	,,	,,	,,	,,	,,	,,	2363.5	1720.2	,,	1077.8	1224.3	2651.4	3579.6	,,
1957-58	,,	,,	,,	,,	,,	,,	,,	,,	,,	1046.9	1190.9	2242.5	,,	,,

TABLE 10

MICA
FLOOD CONTROL STORAGE RESERVATION CURVES
1997-98 OPERATING YEAR
KSFD

	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	3529.2	3529.2	3529.2	3428.4	3428.4	3428.4	3385.7	3347.2	3304.6	3304.6	3304.6	3369.1	3447.9	3529.2
1929-30	,,	,,	,,	,,	,,	,,	3352.6	3284.4	3208.7	3208.7	3208.7	3300.7	3413.2	,,
1930-31	,,	,,	,,	,,	,,	,,	3428.4	3428.4	3428.4	3428.4	3428.4	3457.3	3492.7	,,
1931-32	,,	,,	,,	,,	,,	,,	3105.7	2803.2	2480.5	2480.5	2480.5	2781.5	3149.6	,,
1932-33	,,	,,	,,	,,	,,	,,	3101.7	2807.2	,,	,,	,,	,,	,,	,,
1933-34	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1934-35	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1935-36	,,	,,	,,	,,	,,	,,	3105.7	2803.2	,,	,,	,,	,,	,,	,,
1936-37	,,	,,	,,	,,	,,	,,	3330.6	3242.3	3144.5	3144.5	3144.5	3323.3	3398.4	,,
1937-38	,,	,,	,,	,,	,,	,,	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	,,
1938-39	,,	,,	,,	,,	,,	,,	3193.8	2981.4	2746.8	2746.8	2746.8	2971.4	3246.0	,,
1939-40	,,	,,	,,	,,	,,	,,	3274.3	3130.5	2976.4	2976.4	2976.4	3135.1	3329.1	,,
1940-41	,,	,,	,,	,,	,,	,,	3428.4	3428.4	3428.4	3428.4	3428.4	3457.3	3492.7	,,
1941-42	,,	,,	,,	,,	,,	,,	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	,,
1942-43	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1943-44	,,	,,	,,	,,	,,	,,	3428.4	3428.4	3428.4	3428.4	3428.4	3457.3	3492.7	,,
1944-45	,,	,,	,,	,,	,,	,,	3193.1	2980.2	2745.0	2745.0	2745.0	2970.0	3245.3	,,
1945-46	,,	,,	,,	,,	,,	,,	3101.7	2807.2	2480.5	2480.5	2480.5	2781.5	3149.6	,,
1946-47	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1947-48	,,	,,	,,	,,	,,	,,	3105.7	2803.2	,,	,,	,,	,,	,,	,,
1948-49	,,	,,	,,	,,	,,	,,	3101.7	2807.2	,,	,,	,,	,,	,,	,,
1949-50	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1950-51	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1951-52	,,	,,	,,	,,	,,	,,	3105.7	2803.2	,,	,,	,,	,,	,,	,,
1952-53	,,	,,	,,	,,	,,	,,	3101.7	2807.2	,,	,,	,,	,,	,,	,,
1953-54	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1954-55	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1955-56	,,	,,	,,	,,	,,	,,	3105.7	2803.2	,,	,,	,,	2695.5	3172.7	,,
1956-57	,,	,,	,,	,,	,,	,,	3101.7	2807.2	,,	,,	,,	2781.5	3149.6	,,
1957-58	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,

TABLE 11

COLUMBIA RIVER TREATY
COMPOSITE OPERATING RULE CURVES
FOR THE WHOLE OF CANADIAN STORAGE
END OF MONTH CONTENTS IN KSFD
1997-98 OPERATING YEAR

FLOW YEAR	AUG15	AUG31	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR15	APR30	MAY	JUN	JUL
1928-29	7814.6	7814.6	7498.4	7297.4	6892.4	5829.1	4502.1	2977.2	2987.1	2781.3	2713.6	3697.3	6137.2	7814.6
1929-30	,,	,,	,,	,,	,,	,,	4067.4	2623.8	2368.0	2217.3	2635.9	,,	,,	,,
1930-31	,,	,,	,,	,,	,,	,,	,,	2939.4	2703.1	2542.2	2713.6	3535.1	,,	,,
1931-32	,,	,,	,,	,,	,,	,,	1884.3	786.9	433.4	392.3	504.5	2177.6	5601.6	,,
1932-33	,,	,,	,,	,,	,,	,,	,,	666.5	330.3	283.5	677.1	2226.9	5302.0	,,
1933-34	,,	,,	,,	,,	,,	,,	,,	496.3	0.0	0.0	93.2	2646.2	6079.3	,,
1934-35	,,	,,	,,	,,	,,	,,	3159.0	2026.3	1562.7	1412.2	1462.1	2610.5	5493.5	,,
1935-36	,,	,,	,,	,,	,,	,,	3253.4	2056.2	1512.4	1384.1	1185.1	2576.9	6061.9	,,
1936-37	,,	,,	,,	,,	,,	,,	4502.1	2977.2	2987.1	2781.3	2713.6	3697.3	6137.2	,,
1937-38	,,	,,	,,	,,	,,	,,	2074.1	1116.4	1066.6	1087.9	1582.8	3145.0	5972.6	,,
1938-39	,,	,,	,,	,,	,,	,,	4045.9	2756.4	2528.7	2360.1	2713.6	3617.6	6137.2	,,
1939-40	,,	,,	,,	,,	,,	,,	4030.0	2623.8	2129.2	2074.6	2503.0	3406.2	,,	,,
1940-41	,,	,,	,,	,,	,,	,,	4067.4	2977.2	2987.1	2781.3	2713.6	3697.3	,,	,,
1941-42	,,	,,	,,	,,	,,	,,	3818.2	2835.4	2721.0	2618.9	2681.0	3652.6	6125.6	,,
1942-43	,,	,,	,,	,,	,,	,,	3047.5	1949.9	2443.5	2411.2	2618.4	3628.9	6096.1	,,
1943-44	,,	,,	,,	,,	,,	,,	4502.1	2977.2	2987.1	2781.3	2713.6	3697.3	6137.2	,,
1944-45	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,	,,
1945-46	,,	,,	,,	,,	,,	,,	1884.3	496.3	0.0	0.0	458.0	2225.8	5862.8	,,
1946-47	,,	,,	,,	,,	,,	,,	,,	644.8	429.1	442.5	990.6	2705.0	5917.7	,,
1947-48	,,	,,	,,	,,	,,	,,	,,	496.3	330.0	263.4	711.3	2426.1	5848.7	,,
1948-49	,,	,,	,,	,,	,,	,,	3528.0	2507.9	2442.9	2415.5	2654.8	3642.1	6137.2	,,
1949-50	,,	,,	,,	,,	,,	,,	1884.3	710.8	551.4	523.8	995.8	2586.5	5275.2	,,
1950-51	,,	,,	,,	,,	,,	,,	,,	1001.6	987.3	942.2	1468.8	3032.0	6030.2	,,
1951-52	,,	,,	,,	,,	,,	,,	2132.7	1371.4	1314.9	1252.9	1711.5	3472.9	6075.5	,,
1952-53	,,	,,	,,	,,	,,	,,	2602.6	1910.8	1864.9	1827.9	2216.9	3501.2	6041.6	,,
1953-54	,,	,,	,,	,,	,,	,,	1884.3	496.3	0.0	0.0	263.1	1855.0	5214.8	,,
1954-55	,,	,,	,,	,,	,,	,,	2583.0	1599.2	1257.2	1237.2	1162.0	2382.2	5087.6	,,
1955-56	,,	,,	,,	,,	,,	,,	1884.3	609.1	255.8	207.9	717.0	2595.6	5826.9	,,
1956-57	,,	,,	,,	,,	,,	,,	,,	770.8	432.2	397.5	908.0	2565.3	6092.5	,,
1957-58	,,	,,	,,	,,	,,	,,	,,	765.4	433.1	398.5	693.8	2261.7	5942.2	,,

COLUMBIA RIVER TREATY
DETERMINATION OF DOWNSTREAM POWER BENEFITS

FOR THE ASSURED OPERATING PLAN
FOR OPERATING YEAR 1997-98

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DETERMINATION OF DOWNSTREAM POWER BENEFITS
FOR THE ASSURED OPERATING PLAN
FOR OPERATING YEAR 1997-98

October 1992

1. Introduction

The treaty between Canada and the United States of America relating to the cooperative development of the water resources of the Columbia River Basin requires that downstream power benefits from the operation of Canadian Treaty storage be determined in advance by the two Entities. The purpose of this document is to describe the results of those downstream power benefit computations developed from the 1997-98 Assured Operating Plan (AOP).

The procedures followed in the benefit studies are those provided in Annex A, Paragraph 7, and Annex B of the Treaty; in Articles VIII, IX, and X of the Protocol; in the Entity Agreements, signed 28 July and 12 August, 1988, on Principles and on Changes to Procedures for the Preparation of the Assured Operating Plan and Determination of Downstream Power Benefit Studies (1988 Entity Agreements); and in the document, "Columbia River Treaty Principles and Procedures for Preparation and Use of Hydroelectric Operating Plans" (POP), dated December 1991.

The Canadian Entitlement Benefits were computed from the following studies:

Step I -- operation of the total United States of America planned hydro and thermal system with 15- 1/2 million acre-feet (maf) of Canadian storage operated for optimum power generation in both countries.

Step II -- operation of the United States base hydro and thermal system with 15-1/2 maf of Canadian storage operated for optimum power generation in both countries.

Step III -- operation of the United States base hydro and thermal system operated for optimum power generation in the United States.

As part of the determination of downstream power benefits for the operating year 1997-98, separate determinations were carried out relating to the limit of year-to-year change in benefits attributable to the operation of Canadian Treaty storage in operating plans designed to achieve optimum power generation at-site in Canada and downstream in Canada and the United States of America (joint optimum).

As required by the Canadian Entitlement Purchase Agreement, the decrease in downstream power benefits due to the operation of Canadian Treaty storage for joint optimum power generation, instead of operation of Canadian Treaty storage for optimum power generation in the United States of America only (US optimum), was separately determined.

2. Results of Canadian Entitlement Computations

The Canadian Entitlement to the downstream power benefits in the United States of America attributable to operation in accordance with Treaty Annex A, Paragraph 7, for optimum power generation in Canada and the United States of America, which is one-half the total computed downstream power benefits, was computed to be (See Table 5):

Dependable Capacity	=	1229.6 MW
Average Annual Energy	=	553.3 aMW

3. Computation of Maximum Allowable Reduction in Downstream Power Benefits

In accordance with the Treaty Annex A, Paragraph 7 and Part III, Paragraph 15c(2) of POP, the computation of the maximum allowable reduction in downstream power benefits and the resulting minimum permitted Canadian Entitlement to downstream power benefits for the 1997-98 operating year are based on the formula X - (Y - Z).

The quantities X, Y, and Z, expressed in terms of entitlement to downstream power benefits, are computed as follows:

- X is one-half of the downstream power benefits derived from the previous year's Step II joint optimum and Step III US optimum studies.
- Y is one-half of the downstream power benefits derived from the difference between the previous year's Step II US optimum and Step III US optimum studies.
- Z is one-half of the downstream power benefits derived from the difference between the present year's Step II US optimum with 15 maf of Canadian storage and Step III US optimum studies.

The purpose of this formula is to set a lower limit on the Canadian Entitlement by accumulating the annual reductions resulting from reoperation of Canadian storage as well as the reductions caused by year to year changes in data and by removal of 0.5 MAF storage.

The quantities X and Y were computed in the 1996-97 DDPB. The quantity Z, which is computed from one-half of the downstream power benefits determined for 15 maf of Canadian Treaty storage operated for optimum power generation in the United States of America, is computed in Table 5.

The computation of the formula X - (Y - Z) is as follows:

Dependable Capacity	=	1373.4 - (1372.4 - 1200.6)	=	1201.6 MW
Average Annual Energy	=	547.5 - (548.4 - 545.0)	=	544.1 aMW

The computed Canadian Entitlement exceeds these amounts.

4. Effect on Sale of Canadian Entitlement

The Canadian Entitlement to downstream power benefits attributable to Mica and Arrow for operating year 1997-98 were sold to the United States of America under the Canadian Entitlement Purchase Agreement dated 13 August 1964. The Canadian Entitlement attributable to Duncan Lake storage was sold to the United States of America through 31 March 1998. The studies developed for this sale included the assumption of operation of Treaty storage for optimum power generation downstream in the United States of America only. The Canadian Entitlement determined from the 1997-98 Assured Operating Plan for this condition would have been:

Dependable Capacity	=	1229.6 MW
Average Annual Energy	=	556.1 aMW

Because the 1997-98 Assured Operating Plan was designed to achieve optimum power generation at-site in Canada and downstream in Canada and the United States of America, Section 7 of the Agreement requires that "any reduction in the Canadian Entitlement resulting from action taken pursuant to Paragraph 7 of Annex A of the Treaty shall be determined in accordance with Subsection (3) of Section 6 of this Agreement." A comparison of the Canadian Entitlement for optimum power in Canada and the United States of America with the Canadian Entitlement to downstream power benefits shown above indicates a decrease in Canadian Entitlement of 2.8 MW of average annual usable energy, and no change in dependable capacity.

Accordingly, the Entities are agreed that the United States Entity is entitled to receive 2.8 MW of energy, but not entitled to receive any dependable capacity, during the period 1 April 1997 through 31 March 1998, from the Canadian Entity, in accordance with Sections 7 and 10 of the Canadian Entitlement Purchase Agreement dated 13 August 1964. The compensation to the United States of America for optimum power generation at-site in Canada and downstream in Canada and the United States of America for the period 1 April 1998 through 31 March 1999 will be computed in the 1998-99 AOP and will reflect an adjustment for termination of the sale of benefits attributable to Duncan Lake storage.

5. Canadian Entitlement Return

The sale of the Canadian Entitlement attributable to Duncan Lake storage terminates on 31 March 1998 under section 2. (1)(a) of the Canadian Entitlement Purchase Agreement. Under Section 2. (3) of this agreement, the Canadian Entitlement attributable to Duncan Lake is the ratio of Duncan Lake storage to the whole of Canadian storage. The storage volume at Duncan lake is 1.4 maf while the storage volume of the whole of Canadian storage is 15.5 maf. The obligation of the United States to return Canadian Entitlement to Canada for the period 1 April 1998 through 31 July 1998 is computed to be:

Dependable Capacity	=	1229.6 MW * (1.4maf/15.5maf)	=	111.1 MW
Average Annual Energy	=	553.3 aMW* (1.4maf/15.5maf)	=	50.0 aMW

The dependable capacity and average annual energy were computed from the joint optimum power studies.

6. Summary of Canadian Entitlement Computations

The following Tables and Chart summarize the study results:

Table 1. Determination of Firm Hydro Loads for Step I Studies:

This table shows the loads and resources used in the Step I studies and the computation of the residual hydro load for the Step I study.

Table 2. Determination of Step I Thermal Installations and Thermal Displacement Market:

This table shows the computation of the potential thermal displacement market for the downstream power benefit determination of usable energy. The potential thermal displacement market was limited to the existing and scheduled thermal energy capability including thermal imports after allowance for reserves, minimum thermal generation, and reductions for the thermal resources used outside the PNW Area. Line 14 in the table shows shaped surplus energy.

Table 3. Determination of Loads for 1997-98 Step II and III Studies:

This table shows the computation of the Step II and III loads. The monthly loads for Step II and III studies have the same ratio between each month and the annual average as does the Pacific Northwest (PNW) area load. The PNW area firm loads on this table were based on the joint BPA/Northwest Power Planning Council November 1991 load forecast. The Grand Coulee pumping load is also included in this estimate. The method for computing the firm load for the Step II and III studies is described in the 1988 Entity Agreements and in POP.

Table 4. Summary of Power Regulations from 1997-98 Assured Operating Plan:

This table summarizes the results of the Step I, II, and III power regulation studies for each project and the total system.

Table 5. Computation of Canadian Entitlement For 1997-98 Assured Operating Plan:

A. Optimum Generation in Canada and the U.S.
B. Optimum Generation in the U.S. Only
C. Optimum Generation in the U.S. and a 1/2 Million Acre-Feet Reduction in Total Canadian Treaty Storage

The essential elements used in the computation of the Canadian Entitlement to downstream power benefits, the minimum permitted downstream power benefits, and the reduction in downstream power benefits attributable to the operation of Canadian Treaty storage for optimum power generation in the United States of America only, are shown on this table.

Chart 1. 1997-98 Determination of Downstream Power Benefits 30-Year Monthly Hydro Generation:

This chart shows duration curves of the hydro generation from the Step II and III studies and graphically illustrates the change in the portion of secondary energy that is usable for thermal displacement due to operation of Treaty storage. Secondary energy is the energy capability each month which exceeds the firm hydro loads shown in Table 3. The usable secondary energy in average megawatts for the Step II and III studies is computed in accordance with Annex B, Paragraphs 3(b) and 3(c), as the portion of secondary energy which can displace thermal resources used to meet PNW area loads plus the other usable secondary generation. The Entities have agreed that "the other usable secondary" is computed on the basis of 40 percent of the remainder after thermal displacement.

7. Summary of Changes From Previous Year

Data from the six most recent Assured Operating Plans and their associated Downstream Power Benefits are summarized in Tables 6 and 7. Firm energy shifting was not included in the 1992-93, 1996-97, and the 1997-98 operating plan studies. An explanation of the more important changes compared to last year's studies follows.

(a) Loads and Resources

Loads for the 1997-98 AOP were based on the joint BPA/Northwest Power Planning Council November 1991 load forecast. The Pacific Northwest Area firm energy load increased by 62.7 annual average MW (aMW). The total exports, not including firm surplus energy, increased by 415.1 aMW, resulting in a 477.8 aMW total increase in system firm load in the Step I studies. Most of the increase in exports is due to additional export sales to the southwest.

The load for return of the Canadian Energy Entitlement resulting from Duncan Lake storage for the period 1 April 1998 through 31 July 1998 was estimated at 50.0 aMW. The actual Canadian Energy Entitlement obligation for the same period was computed to be 50.0 aMW. Similarly, the Canadian Capacity Entitlement was estimated to be 124 MW for purposes of running the hydro regulation studies. The actual Canadian Capacity Entitlement was computed to be 111.1 MW.

The total energy capability of the thermal installations increased by 168.7 aMW. Major thermal increases included: 1) large thermal resources increased by 106.7 aMW, mostly due to increased plant factors at existing plants; 2) Co-generation increased by 75.7 aMW, due to increased plant factors at existing projects and the addition of Spokane Municipal Solid Waste project.

(b) Operating Procedures

The 1980 level modified base flows were used with no depletion to the 1998 level based on the recommendation of the Columbia River Water Management Group. Coulee pumping adjustments were included, however. There was a substantial increase in critical period generation in Step I and Step II studies due to the lower level of irrigation depletions. Updated irrigation depletions had little effect on Step III critical period generation due to the lack of irrigation during the critical period months, November 1936 through April 1937. Critical period generation also increased in the Step I and Step II studies due to the expected installation of fish bypass facilities in January 1998 and the associated reduction in spill at The Dalles. The net Step I critical period generation increase was approximately 98 MW.

The 1997-98 AOP studies used a new optimizer for the critical period studies. The HYDROSIM Model was used for AOP hydroregulation studies for the second year.

For the first time, the Step II and Step III refill studies included the contents of Corra Linn and Brownlee when assessing system refill. These plants were included because they are part of the Base System as defined in the Treaty. The Step I study did not include the contents of Brownlee or Corra Linn when assessing refill because they are not included in Coordination Agreement refill studies.

(c) Step III Critical Period

The Step III study had a critical period of 6 months, 1 November 1936 through 30 April 1937. The Step III critical period in the previous AOP was 7 months, 1 October 1936 through 30 April 1937.

(d) Downstream Power Benefits Computation

The Canadian capacity entitlement decreased from 1373.4 MW in the 1996-1997 DDPB to 1229.6 MW in the 1997-1998 DDPB for a reduction of 143.8 MW. The primary reason for the capacity entitlement reduction is the shorter Step III critical period in the 1997-1998 DDPB, which resulted in a 273.9 MW increase in the Step III average critical period generation. The Step II average critical period generation increased by 54.5 MW compared to the 1996-1997 DDPB due to updated irrigation depletions. Therefore, the difference between the Step II and Step III average critical period generation decreased as did the capacity entitlement.

The Canadian energy entitlement increased from 547.5 aMW in the 1996-1997 DDPB to 553.3 aMW in the 1997-1998 DDPB, an increase of 5.8 aMW. Several data updates increased the energy entitlement while changes in thermal maintenance schedules decreased the energy entitlement. Data updates include: irrigation depletions, energy content curve lower limits, and power discharge requirements. The net effect of all changes was a small increase in the energy entitlement.

TABLE 1
1997-98 ASSURED OPERATING PLAN
DETERMINATION OF FIRM HYDRO LOADS FOR STEP I STUDIES

ENERGY LOAD OF THE PACIFIC NORTHWEST AREA (Avg MW)							ENERGY RESOURCES (Avg MW)										
PERIOD	PNW AREA LOAD 1/	ANNUAL LOAD SHAPE PERCENT	FIRM EXPORTS 2/	MAINT 3/	FIRM SURPLUS 4/	TOTAL STEP I STUDY LOAD 5/	HYDRO INDEP (1929)	IMPORTS 6/	LARGE THERMAL	SMALL THERMAL	COMBST TURBINE	PURPA NUGS	COGEN	RENEW	MISC 7/	TOTAL (1929) 8/	REGULATED HYDRO LOAD (ENERGY) (1929) 9/
Aug. 1-15	18965	93.12	1203	32	0	20220	1149	1261	5475	63	868	387	710	47	17	9997	10223.0
Aug. 16-31	18907	92.74	1203	27	0	20137	1173	1248	5475	63	758	387	710	47	17	9878	10259.0
September	18289	89.71	1209	9	0	19507	980	931	5475	63	797	365	710	48	17	9386	10121.0
October	19108	93.72	832	9	0	19949	973	1142	5475	63	1015	353	710	48	17	9796	10153.0
November	21164	103.81	778	4	0	21944	1048	1788	5475	69	987	350	710	48	17	10492	11452.0
December	22644	111.07	795	0	0	23439	1122	2047	5475	62	1041	335	710	48	17	10857	12582.0
January	23455	115.05	775	0	0	24230	1029	2017	5475	69	1043	345	710	48	17	10753	13477.0
February	22356	109.66	725	0	0	23081	707	1998	5475	69	1040	353	710	48	17	10417	12664.0
March	21089	103.44	774	5	0	21868	933	1648	5273	63	863	365	710	48	17	9920	11948.0
April 1-15	19948	97.85	825	7	0	20780	1150	1277	3963	63	496	413	710	48	17	8137	12643.0
April 16-30	20046	98.33	825	8	0	20879	1216	1151	3268	63	558	413	710	48	17	7442	13437.0
May	19278	94.56	764	20	3000	23062	1637	1136	2201	63	948	440	302	48	17	6792	16270.0
June	19198	94.17	1168	16	2171	22553	1441	1171	4132	63	962	445	538	3	17	8772	13781.0
July	19222	94.28	1259	51	0	20532	1134	1302	5475	56	1007	417	710	48	17	10168	10366.0
Annual Average =	20387.3	100.00	928.3	12.7	433.2	21759.6	1115.1	1468.5	4916.6	63.8	921.0	380.8	661.2	44.2	17.0	9588.1	12171.4
Crit Per Avg (42mo)	20499.2		915.7	11.4	371.5	21797.8		1494.8	4998.1	64.1	930.5	376.4	666.2	44.8	17.0		
August 1-31	18944.7	92.92	1203.00	29.5	0.0	20178.5	1161.0	1254.5	5475.0	63.0	823.0	387.0	710.0	47.0	17.0	9937.5	10241.0
April 1-30	19997.0	98.09	825.00	7.5	0.0	20829.5	1183.0	1214.0	3615.5	63.0	526.0	376.0	[illegible]	47.5	17.0	7789.5	13040.0

PEAK LOAD OF THE PACIFIC NORTHWEST AREA (MW)							PEAK RESOURCES (MW)										
PERIOD	PNW AREA LOAD 1/	LOAD FACTOR PERCENT	FIRM EXPORTS 2/	MAINT 3/	FIRM SURPLUS 4/	TOTAL STEP I STUDY LOAD 5/	HYDRO INDEP (1929)	IMPORTS 6/	LARGE THERMAL	SMALL THERMAL	COMTRB	PURPA NUGS	COGEN	RENEW	MISC 7/	TOTAL (1929) 8/	REGULATED HYDRO LOAD (PEAK) (1929) 9/
Aug. 1-15	23632	80.17	2323	4629	0	30584	1917	1684	6302	78	1236	425	734	49	0	12425	18159.0
Aug. 16-31	23587	80.17	2323	4066	0	29976	1899	1684	6302	78	1058	425	734	49	0	12229	17747.0
September	23782	76.90	2336	3787	0	29905	1785	1247	6302	78	1176	405	734	50	0	11777	18128.0
October	26257	72.77	1496	3208	0	30961	1710	1509	6302	78	1438	390	734	50	0	12211	18750.0
November	28766	73.57	1058	2935	0	32759	1774	2497	6302	167	1427	388	734	50	300	13639	19120.0
December	30707	73.74	1036	2037	0	33780	1809	2591	6302	147	1435	373	734	50	300	13741	20039.0
January	31882	73.57	1036	1561	0	34479	1761	2632	6302	167	1468	384	734	50	300	13798	20681.0
February	30837	72.50	1036	2295	0	34168	1339	2586	6302	167	1462	390	734	50	300	13330	20838.0
March	28355	74.37	1035	2646	0	32036	1748	2083	6210	78	1029	402	734	50	300	12634	19402.0
April 1-15	27019	73.79	1156	2751	0	30926	1998	1411	4721	78	900	449	734	50	0	10341	20585.0
April 16-30	27101	73.79	1156	2483	0	30740	2038	1408	3765	78	861	449	734	50	0	9383	21357.0
May	25756	74.85	1579	2360	4657	34352	2167	1778	2511	78	1364	502	331	50	0	8781	25571.0
June	24398	78.69	2377	2204	2759	31738	2096	1778	4182	78	1355	506	576	3	0	10574	21164.0
July	24170	79.53	2450	3725	0	30345	1579	1719	6302	58	1414	454	734	50	0	12310	18035.0
Avg Crit Per Load Factor		75.17															
August 1-31	23632	80.17	2323	4629	0	30584	1917	1684	6302	78	1236	425	734	49	0	12425	18159.0
April 1-30	27101	73.79	1156	2751	0	30926	2038	1411	4721	78	900	449	734	50	0	10341	21357.0

1/ The PNW Area load does not include the exports, but does include irrigation pumping. The computation of the load shape for Step II/III studies uses these loads.
2/ Firm exports include 794 avg. annual MW of firm exports and 132 avg. annual MW of seasonal exchange exports that have a matching import.
3/ Hydro maintenance is treated as a load instead of a modeled resource reduction.
4/ All firm surplus energy is assumed to be exported outside of the PNW Area.
5/ The total Step I study load is the sum of PNW Area load, firm exports, maintenance, and firm surplus.
6/ Imports include 132 average annual MW of seasonal exchanges.
7/ Miscellaneous includes Energy Management System, (an energy resource, no peaking) and Coulee Pump Turbine (a peaking resource, no energy).
8/ Total resources other than regulated hydro projects, based on 1929 water conditions for hydro independents.
9/ The regulated hydro load is the total Step I study load minus Step I nonregulated resources i.e., the net firm load met by the Step I regulated hydro projects.

TABLE 2
1997-98 ASSURED OPERATING PLAN
DETERMINATION OF STEP I THERMAL INSTALLATIONS AND THERMAL DISPLACEMENT MARKET

(Energy in Average MW)

	Aug15	Aug31	Sept	Oct.	Nov.	Dec.	Jan.	Feb.	March	Apr15	Apr30	May	June	July	Annual Average
THERMAL INSTALLATIONS															
1. Large Thermal	5475	5475	5475	5475	5475	5475	5475	5475	5273	3963	3268	2201	4132	5475	4916.6
2. Combustion Turbines	888	758	797	1015	987	1041	1043	1040	863	496	556	948	962	1007	921.0
3 . Co-Generation	710	710	710	710	710	710	710	710	710	710	710	302	538	710	661.2
4. Small Thermal	63	63	63	63	69	62	69	69	63	63	63	63	63	56	63.8
5. Renewable Thermal	47	47	48	48	48	48	48	48	48	48	48	48	3	48	44.2
6. NUGS Thermal (60% of total)	232	232	219	212	210	201	207	212	219	248	248	264	267	250	228.5
7. Minus Plant Sales included above (-)	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-40	-71	-102	-94.2
8. Total Thermal Imports	1241	1228	916	1121	1752	2000	1957	1928	1587	1248	1121	1108	1132	1276	1431.0
9. Minus Seasonal Exch. Imports Incl. (-)	0	0	0	0	-300	-412	-404	-399	-103	0	0	0	0	0	-133.3
10. ...Total Step I Thermal Installations	8554	8411	8126	8542	8849	9023	9003	8981	8558	6674	5912	4894	7026	8720	8038.7
SYSTEM SALES															
11. Total Exports	1203	1203	1209	832	776	795	775	725	774	825	825	764	1168	1259	926.3
12. Minus Plant Sales Exports (-)	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-102	-40	-71	-102	-94.2
13. Minus Seasonal Exch. Exports (-)	-400	-400	-398	-22	0	0	0	0	0	0	0	0	-358	-400	-132.0
14. Added Surplus Firm Sales	0	0	0	0	0	0	0	0	0	0	0	3000	2171	0	433.2
15. ...Total System Sales	701	701	709	708	674	693	673	623	672	723	723	3724	2910	757	1133.4
16. Uniform Avg. Annual System Sales	1133	1133	1133	1133	1133	1133	1133	1133	1133	1133	1133	1133	1133	1133	1133.4
MINIMUM THERMAL GENERATION															
17. Large Thermal Minimum Generation	407	395	673	721	729	744	731	713	694	370	316	370	338	394	570.3
18. Cogen & SM Thermal Min. Generatior	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40.0
19. NUGS Thermal Min Gen	193	193	183	177	175	168	173	177	183	207	207	220	223	208	190.4
20. ...Total Minimum Generation	640	628	896	938	944	952	944	930	917	617	563	630	601	642	800.7
21. THERMAL DISPL. MARKET	6780	6649	6097	6471	6772	6938	6926	6918	6508	4924	4216	3131	5292	6944	6104.6

NOTES:

- Lines 7 & 12 Plant sales include Longview Fibre and 15 percent of Boardman.
- Lines 9 & 13 Seasonal exchanges with extraregional utilities. Thermal imports are not included as thermal resources and exports are not included with system sales.
- Line 10 Thermal installations using the total Step I thermal generation, except seasonal exchanges and plant sales, per 1988 Entity Agreement. Sum of lines 1 to 9.
- Line 15 System Sales are total exports excluding plant sales and seasonal exchanges. Lines 11+12+13+14.
- Line 16 Average Annual System Sales shaped uniformly per 1988 Entity Agreement assumption that shaping is supported by hydro system.
- Lines 17 & 18 Large Thermal min generation is Centralia, Jim Bridger, Valmy, & 90% Mont Thrm Imp. Cogen Therm is Spokane Muni Solid Waste & Tacoma Steam Plant. Small Thermal is James River (EWEB).
- Line 19 60% of the total NUGS is thermal. Displaceable NUGS generation is 16.7% of the thermal NUGS.
- Line 21 PNW Area Thermal Displacement Market is the Total Displaceable Thermal Resources used to meet PNW Area firm loads. Line 10 - 16 - 20.

TABLE 3
1997-98 ASSURED OPERATING PLAN
DETERMINATION OF LOADS FOR
STEP II AND STEP III STUDIES

LOAD OF THE PACIFIC NORTHWEST AREA						STEP II STUDY		STEP III STUDY		
Period	PNW Area Energy Load 1/ aMW	Annual Energy Load Shape Percent	Peak Load MW	Load Factor Percent	Energy Capability of Thermal Installations 2/ aMW	Total Load 3/ aMW	Hydro Load 4/ aMW	Total Load 3/ aMW	Hydro Load 4/ aMW	Period
Aug. 1-15	18985	93.12	23632	80.17	8554	15832.1	7278.1	13611.8	5057.8	Aug. 1-15
Aug. 16-31	18907	92.74	23587	80.17	8411	15767.1	7356.1	13555.9	5144.9	Aug. 16-31
September	18289	89.71	23782	76.90	8126	15251.7	7125.7	13112.8	4986.8	September
October	19108	93.72	26257	72.77	8542	15934.7	7392.7	13700.0	5158.0	October
November	21164	103.81	28766	73.57	8849	17649.3	8800.3	15174.1	6325.1	November
December	22644	111.07	30707	73.74	9023	18883.5	9860.5	16235.3	7212.3	December
January	23455	115.05	31882	73.57	9003	19559.8	10556.8	16816.7	7813.7	January
February	22356	109.66	30837	72.50	8981	18643.3	9662.3	16028.8	7047.8	February
March	21089	103.44	28355	74.37	8558	17586.7	9028.7	15120.4	6562.4	March
April 1-15	19948	97.85	27019	73.79	6674	16635.2	9961.2	14302.3	7628.3	April 1-15
April 16-30	20046	98.33	27101	73.79	5912	16716.9	10804.9	14372.5	8460.5	April 16-30
May	19278	94.56	25756	74.85	4894	16076.5	11182.5	13821.9	8927.9	May
June	19198	94.17	24398	78.69	7026	16009.8	8983.8	13764.5	6738.5	June
July	19222	94.28	24170	79.53	8720	16029.8	7309.8	13781.8	5061.8	July
Annual Average =	20387.3	100.00		75.39	8038.7	17001.6	8962.9	14617.3	6578.6	Annual Avg
Critical Period Avg =	20499.2			75.17	8140.7	17211.3	9018.0	15621.5	7169.4	Crit.Per.Avg
Step II Crit. Per. Avg =	20638.8				8193.3					
Step III Crit. Per. Avg=	21788.0				8452.1	Input 5/=	9018.0	Input 5/=	7169.4	
August 1-31	18944.7	92.92	23632.0	80.17	8480.2	15798.6	7318.4	13583.0	5102.8	Aug. 1-31
April 1-30	19997.0	98.09	27101.0	73.79	6293.0	16676.1	10383.1	14337.4	8044.4	Apr. 1-30

1/ The PNW Area load does not include the exports, but does include pumping. The computation of the load shape for Step II/III studies used these loads.
2/ The thermal installations include all thermal used to meet the Step I system load.
3/ The total firm load for the Step II/III studies is computed to have the same shape as the load of the PNW Area.
4/ The hydro load is equal to the total load minus the Step I study thermal installations.
5/ Input is the assumed critical period average generation for the Step II/III hydro studies and is used to calculate the residual hydro loads.

TABLE 4
SUMMARY OF POWER REGULATIONS
FROM 1997-98 ASSURED OPERATING PLAN

PROJECTS	BASIC DATA		STEP I			STEP II				STEP III			
	NUMBER OF UNITS	NOMINAL INSTALLED PEAKING CAPACITY MW	USABLE STORAGE 1000 AF	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	USABLE STORAGE 1000 AF	JANUARY 1945 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW	USABLE STORAGE 1000 AF	JANUARY 1937 PEAKING CAP. MW	CRITICAL PERIOD AVERAGE GEN. MW	30 YEAR AVERAGE ANNUAL GEN. MW
HYDRO RESOURCES													
CANADIAN													
Mica			7000			7000							
Arrow			7100			7100							
Duncan			1400			1400							
Subtotal			15500			15500							
BASE SYSTEM													
Hungry Horse	4	428	3072	328	98	3008	205	115	105	3008	346	191	104
Kerr	3	180	1219	156	121	1219	153	111	123	1219	150	141	121
Thompson Falls	6	40	0	40	38	0	40	39	37	0	40	40	36
Noxon Rapids	5	554	231	536	152	0	554	134	204	0	554	171	204
Cabinet Gorge	4	230	0	230	100	0	230	87	118	0	230	108	118
Albeni Falls	3	49	1155	21	24	1155	20	23	22	1155	21	18	21
Box Canyon	4	74	0	71	46	0	70	45	48	0	70	55	46
Grand Coulee	24+3SS	6684	5185	6382	2031	5072	6382	1777	2317	5072	5754	1203	2270
Chief Joseph	27	2614	0	2586	1108	0	2586	1008	1346	0	2586	737	1276
Wells	10	840	0	840	413	0	840	385	477	0	840	292	437
Rocky Reach	11	1267	0	1267	576	0	1267	534	690	0	1267	393	649
Rock Island	18	544	0	544	280	0	544	261	328	0	544	189	300
Wanapum	10	986	0	986	518	0	986	482	599	0	986	345	542
Priest Rapids	10	912	0	912	498	0	912	470	561	0	912	351	504
Brownlee	5	675	975	675	230	974	675	302	298	974	675	289	298
Oxbow	4	220	0	220	95	0	220	120	121	0	220	121	121
Ice Harbor	6	693	0	693	226	0	693	240	309	0	693	196	309
McNary	14	1127	0	1127	659	0	1127	634	799	0	1127	504	745
John Day	16	2484	535	2484	935	0	2484	911	1233	0	2484	718	1200
The Dalles	22+2F	2074	0	2074	748	0	2074	725	984	0	2074	589	965
Bonneville	18+2F	1147	0	1147	596	0	1147	576	726	0	1147	469	691
Kootenay Lake	0	0	673	0	0	673	0	0	0	673	0	0	0
Chelan	2	54	677	51	36	676	51	37	45	676	51	51	42
Coeur d'Alene Lake	0	0	223	0	0	223	0	0	0	223	0	0	0
Total Base System Hydro		23856	29446	23370	9526	28500	23260	9018	11490	13000	22771	7169	11000
ADDITIONAL STEP I PROJECTS													
Libby	5	600	4980	581	196								
Boundary	6	1055	0	855	369								
Spokane River Plants	24	156	104	159	99								
Hells Canyon	3	450	0	444	184	NOT APPLICABLE TO STEP II				NOT APPLICABLE TO STEP III			
Dworshak	3	450	2015	447	184								
Lower Granite	6	932	0	932	217								
Little Goose	6	932	0	932	218								
Lower Monumental	6	932	0	932	222								
Pelton, Rereg., & Round Butte	7	423	274	418	127								
Subtotal		5930	7373	5680	1816								
THERMAL INSTALLATION 1/													
Large Thermal				6302	4996		6302	5038			6302	5132	
Combustion Turbines (All Displ.)				1468	930		1468	918			1468	916	
Co-GEN. (All Displ.)				734	668		734	681			734	710	
Small Thermal				167	64		167	64			167	66	
Renewable Thermal (All Displ.)				50	44		50	46			50	48	
PURPA Thermal (60% of total)				230	227		230	223			230	216	
Minus Plant Sales included above (-)				-116	-95		-116	-97			-116	-102	
Total Thermal Imports				2461	1457		2461	1481			2461	1734	
Minus Seas. Exch. Imports incl. (-)				-782	-150		-782	-161			-782	-269	
Total Thermal Installations				10514	8141		10514	8193			10514	8452	
RESERVES 2/				-2551	0		-2127	0			-1829	0	
TOTAL RESOURCES				37013	19484		31647	17211			31456	15621	
ESTIMATED LOAD PACIFIC NORTHWEST AREA 3/				31882	20499		26587	17211			22859	15621	
Firm Exports				1036	916								
Minus Seas. Exch. Imports				-782	-150								
Minus Plant Sales				-116	-95								
Surplus Firm Exports				0	371								
Firm Imports (not incl. Thermal Imports)				-170	-38								
Miscellaneous Resources 4/				-154	-168								
Other Coordinated Hydro				-2329	-882								
Independent Hydro Resources				-1601	-982								
Estimated Hydro Maintenance				1561	11								
TOTAL STEP I LOADS				29327	19483								
SURPLUS				7686	1		5060	0			8598	0	
CRITICAL PERIOD	Starts		September 1, 1928			September 1, 1943				November 1, 1936			
	Ends		February 29, 1932			April 30, 1945				April 30, 1937			
	Length (Months)		42 Months			20 Months				6 Months			
	Study Identification		98-41			98-42				98-13			

1/ Thermal energy capabilities are based on an annual plant factor of 80 percent the first full year of operation and 75 percent thereafter unless specified differently by project owner. These annual plant factors include deductions for energy reserves and scheduled maintenance.
2/ Peak reserves are 8 percent of peak load from Table 3; energy reserve deductions have been included in thermal plant energy capability.
3/ Step II or III Peak Load is equal to the Step II or III Annual Average Load multiplied by the ratio of the PNW Area January Peak Load to the Annual Average Load.
4/ Non thermal miscellaneous include 40% PURPA plus Energy Management System.

TABLE 5

COMPUTATION OF CANADIAN ENTITLEMENT FOR
1997-98 ASSURED OPERATING PLAN

A. Optimum Power Generation in Canada and the U.S. (From 98-42)
B. Optimum Power Generation in the U.S. Only (From 98-12)
C. Optimum Power Generation in the U.S. and a 1/2 Million Acre-Feet Reduction in Total Canadian Treaty Storage (From 98-22)

Determination of Dependable Capacity Credited to Canadian Storage - MW

	(A)	(B)	(C)
Step II - Critical Period Avg. Generation 1/	9018.0	9017.9	8974.4
Step III - Critical Period Avg. Generation 2/	7169.4	7169.4	7169.4
Gain Due to Canadian Storage	1848.6	1848.5	1805.0
Average Critical Period Load Factor in % 3/	75.17	75.17	75.17
Dependable Capacity Gain 4/	2459.2	2459.1	2401.2
Canadian Share of Dependable Capacity 5/	1229.6	1229.6	1200.6

Determination of Increase in Average Annual Usable Energy - Average MW

Step II (with Canadian Storage) 1/	(A)	(B)	(C)
Annual Firm Hydro Energy 6/	8963.0	8963.0	8920.0
Thermal Replacement Energy 7/	2037.7	2044.4	2059.7
Other Usable Secondary Energy 8/	194.9	193.9	199.3
System Annual Average Usable Energy	11195.6	11201.3	11179.0
Step III (without Canadian Storage) 2/			
Annual Firm Hydro Energy 6/	6579.0	6579.0	6579.0
Thermal Replacement Energy 7/	2902.9	2902.9	2902.9
Other Usable Secondary Energy 8/	607.2	607.2	607.2
System Annual Average Usable Energy	10089.1	10089.1	10089.1
Average Annual Usable Energy Gain 9/	1106.5	1112.2	1089.9
Canadian Share of Avg. Annual Energy Gain 5/	553.3	556.1	545.0

1/ Step II values were obtained from the 98-42, 98-12, and 98-22 studies, respectively.
2/ Step III values were obtained from the 98-13 study.
3/ Critical period load factor from Table 3.
4/ Dependable Capacity Gain credited to Canadian storage equals gain in critical period average generation divided by the average critical period load factor.
5/ One-half of Dependable Capacity or Usable Energy Gain.
6/ From 30-year average firm load served.
7/ Avg. secondary generation limited to Potential Thermal Displacement market.
8/ Forty percent (40%) of the remaining secondary energy.
9/ Difference between Step II and Step III Annual Average Usable Energy.

TABLE 6

COMPARISON OF
RECENT ASSURED OPERATING PLAN STUDIES

	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98
MICA TARGET OPERATION (ksfd or cfs)						
- AUG 1	3456.2	3456.2	3456.2	3456.2	3456.2	3456.2
- AUG 2	FULL	FULL	FULL	FULL	FULL	FULL
- SEP	FULL	FULL	FULL	FULL	FULL	FULL
- OCT	FULL	10000	3428.4	3428.4	14000.0	15000.0
- NOV	3246.2	19000	22000	22000	19000.0	19000.0
- DEC	22000	22000	24000	24000	23000.0	23000.0
- JAN	27000	26000	27000	27000	24000.0	24000.0
- FEB	25000	25000	25000	25000	20000.0	22000.0
- MAR	23000	22000	25000	25000	19000.0	19000.0
- APR 1	27000	25000	24000	24000	156.2	106.2
- APR 2	10000	18000	14000	14000	0.0	0.0
- MAY	10000	10000	10000	10000	10000.0	10000.0
- JUN	10000	10000	10000	10000	10000.0	10000.0
- JUL	3256.2	3256.2	3356.2	3356.2	3356.2	3356.2
CANADIAN TREATY CRC1 STORAGE DRAFT (ksfd)						
NOV 1928 (-41)	690.3	761.6	1272.6	1272.7	1481.7	922.2
APR 1929 (-41)	7368.5	7754.1	7801.6	7801.6	7708.8	7727.7
JUL 1929 (-41)	1036.3	1139.5	1140.5	1140.5	1028.6	951.2
AUG 1929 (-41)	560.0	983.4	1060.4	1060.4	483.2	864.3
NOV 1928 (-11)	690.3	501.7	1275.3	1275.3	1483.6	923.3
JUL 1929 (-11)	1036.3	1143.0	1142.8	1142.8	1036.6	955.2
STEP I GAINS AND LOSSES DUE TO REOPERATION (MW)						
- U.S. Firm Energy	0.0	-1.4	-4.4	-4.4	-2.0	-0.9
- U.S. Dependable Capacity	-6.0	3.0	2.0	2.0	3.0	-4.0
- U.S. Secondary Energy	16.8	-8.1	2.9	2.9	1.2	13.9
- BCH Firm Energy	87.1	40.1	56.0	56.0	36.0	46.7
- BCH Dependable Capacity	1.0	-14.0	16.0	16.0	-10.0	19.0
- BCH Secondary Energy	-63.2	-27.0	-38.3	-38.3	-36.9	-43.5
HYDROREG SECONDARY LOAD (MW)						
- AUG 1	11070	10655	11475	11475	14510	14547
- AUG 2	11070	10655	11475	11475	14396	14416
- SEP	9981	10092	11466	11466	14147	13878
- OCT	9981	10237	12021	12021	14616	14674
- NOV	9864	10083	12272	12272	15412	15411
- DEC	9857	10074	12443	12443	15951	15835
- JAN	10996	10914	12633	12633	16000	15832
- FEB	10990	10765	12641	12641	15884	15841
- MAR	10757	10405	11909	11909	15031	15160
- APR 1	10390	10235	11817	11817	13840	14436
- APR 2	10164	10933	11573	11573	13267	14391
- MAY	7156	7114	8114	8114	10734	10297
- JUN	10615	10079	11236	11236	14260	11748
- JUL	11081	10740	11590	11590	14648	14843

TABLE 7

COMPARISON OF RECENT DDPB STUDIES

	1992-93	1993-94	1994-95	1995-96 1/	1996-97	1997-98
PNW AREA AVG. ANNUAL LOAD (MW)	18228.0	18370.0	18898.0	18898.0	20324.6	20387.3
-Avg. Annual/Jan. Load (%)	87.7	86.7	86.7	86.7	87.1	86.9
-Avg. C.P. Load Factor (%)	69.0	72.4	75.2	75.2	75.3	75.2
-Avg. Annual Firm Exports	444.0	969.0	905.0	905.0	511.2	926.3
-Avg. Annual Firm Surplus (MW) 2/	388.0	255.0	255.0	255.0	610.5	433.2
THERMAL INSTALLATIONS (MW) 3/						
-January Peak Capability	9218	9220	9225	9225	10381	10514
-Critical Period (C.P.) Energy	5912	6256	6491	6491	7975	8141
-C.P. Minimum Generation	1916	1881	1621	1621	675	632
-Avg. Annual System Export Sales	832	1146	1440	1440	887	1133
-Avg. Ann. Displaceable Market	3095	2689	3462	3462	6104 4/	6105
INSTALLED HYDRO CAPACITY (MW)	29737	29745	29680	29680	29785	29786
-Base System	23808	23806	23736	23736	23841	23856
STEP I/II/III C.P. (MONTHS)	42/20/7	42/20/5.5	42/20/6	42/20/6	42/20/7	42/20/6
BASE STREAMFLOWS AT THE DALLES (cfs)						
-Step I 50-yr.Avg. Streamflow	175456	178235	179502	179502	179338	180748 5/
-Step I C.P. Average	112920	112843	113177	113177	113053	114127
-Step II C.P. Average	99637	99548	100146	100146	100036	101008
-Step III C.P. Average	60661	57498	64733	64733	64756	64870
CAPACITY BENEFITS (MW)						
-Step II C.P. Generation	8909.4	8869.5	8892.9	8892.9	8963.5	9018.0
-Step III C.P. Generation	6871.9	7036.3	7113.5	7113.5	6895.5	7169.4
-Step II Gain over Step III	2037.5	1833.2	1779.4	1779.4	2068.0	1848.6
-CANADIAN ENTITLEMENT	1476.9	1266.5	1183.4	1183.4	1373.4	1229.6
-Change due to Mica Reop	0	-2.3	0.7	0.7	1.0	0.0
-Benefit in Sales Agreement	844.0	755.0	666.0	576.0	486.0	471.0
ENERGY BENEFITS (aMW)						
-Step II Firm Hydro	8898.2	8970.2	8928.3	8928.3	8871.0	8963.0
-Step II Thermal Displacement	1327.0	1148.2	1422.3	1422.3	2037.4	2037.7
-Step II Other Usable	484.0	492.8	421.0	421.0	207.0	194.9
-Step II Total Usable	10709.2	10611.1	10771.6	10771.6	11115.4	11195.6
-Step III Firm Hydro	6659.0	6485.2	6401.4	6401.4	6445.0	6579.0
-Step III Thermal Displacement	1922.4	1783.1	2123.8	2123.8	2951.6	2902.9
-Step III Other Usable	940.5	1031.4	940.0	940.0	623.7	607.2
-Step III Total Usable	9521.9	9299.7	9465.2	9465.2	10020.3	10089.1
-CANADIAN ENTITLEMENT	593.7	655.7	653.2	653.2	547.5	553.3
-Change due to Mica Reoperation	1.4	4.6	-2.0	-2.0	-0.9	-2.8
-ENTITLEMENT in Sales Agreement	305.0	293.0	279.0	268.0	254.0	246.0
STEP II PEAK CAPABILITY (MW)	30518	30579	30530	30530	31472	31647
STEP II PEAK LOAD (MW)	24645	24414	24069	24069	26252	26587
STEP III PEAK CAPABILITY (MW)	30612	30429	30299	30299	31409	31456
STEP III PEAK LOAD (MW)	20893	20593	20273	20273	22350	22859

FOOTNOTES FOR TABLE 7

1. The 1994-95 AOP was carried foreward and adopted for 1995-96 AOP.

2. Average annual firm surplus is the additional shaped load including the surplus shaped in May and/or June.

3. Thermal installations include all existing and planned thermal resources. Beginning with the 1994-95 Assured Operating Plan, thermal installations also included thermal imports. Beginning with the 1996-97 Assured Operating Plan, thermal installations also included cogeneration, renewable thermal, and PURPA, minus plant sales, and seasonal exchange imports.

4. The increased thermal installations beginning with 1996-97 are due to increased plant factors at existing plants, the addition of new cogeneration projects and the inclusion of PURPA resources as thermal installations.

5. The 1997-98 studies did not update irrigation depletions from the 1980 level modified flows. However, there is an adjustment for Grand Coulee pumping.

CHART 1
1997-98 DETERMINATION OF DOWNSTREAM POWER BENEFITS 30-YEAR MONTHLY HYDRO GENERATION (aMW)